STATEMENT OF BASIS
CLASS IID PERMIT APPLICATION
RESOLUTE NATURAL RESOURCES COMPANY

U.S. Environmental Protection Agency, Region IX (EPA)
Underground Injection Control (UIC) Permit NN207000002
Aneth Unit C-113 LDVL Class IID Injection Well
San Juan County, Utah
Lease Nos. SL 070968-A and SL 067907
API No. 4303731852

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BACKGROUND INFORMATION

Resolute Natural Resources Company ("Applicant") has applied for a permit to construct and operate a horizontal Class II disposal well. The vertical portion of the well is located on BLM land in Section 13 and, along with two of four lateral wellbores, is subject to the Utah Division of Oil Gas and Mining as the Underground Injection Control (UIC) permitting authority. The remaining two lateral wellbores are located partially under Navajo Nation surface trust land, in the south-half of Sections 12, Township 40 South, Range 23 East and the southwest quarter of Section 7, Township 40 South, Range 24 East in San Juan County, Utah, and are subject to federal EPA UIC permitting authority. The well is identified as the Aneth Unit C-113 LDVL. The Permittee has applied to Utah DOGM and US EPA Region IX for a UIC permit to allow well construction and operation at an average injection rate of 7,500 barrels per day and a maximum injection rate of 10,000 barrels per day and a maximum wellhead injection pressure of 4,000 psig.

The EPA has decided to approve this permit, pending public review and comment, and is now issuing a Draft Permit. If approved, the permit will be issued for a period of ten (10) years, unless the permit is terminated or modified for reasonable cause (40 CFR §§144.39, 144.40, and 144.41). The permit will be reviewed by EPA every five years.

The Applicant has also submitted a request for a temporary emergency permit on the basis of provisions at 40 CFR §144.34(a)(3), which authorize EPA to issue a temporary emergency Class II injection well permit when the Applicant demonstrates that failure to do so would cause a substantial delay in oil production. Resolute has presented an adequate demonstration that satisfies that requirement. Resolute states that without the authority to dispose of excess produced water in the subject well after November 1, 2007, incremental CO_2 enhanced oil recovery of approximately 1850 barrels per day will be delayed by the length of time for the final permit to be issued, due to a lack of injection well capacity to inject CO_2 and excess produced water in the Aneth Unit. Alternatively, some oil producing wells would have to be shut to limit the volume of salt water produced that would have to be injected into the C-113 SWD well as CO_2 injection increases in the Aneth Unit CO_2 EOR expansion project.

Based on the above, EPA has issued the temporary emergency permit pending a final permit decision after the close of the 30-day public comment period. The temporary emergency permit, Permit No. NN207000004, became effective on October 31, 2007, and will automatically expire upon issuance or denial of the final permit or 90 days after issuance of the temporary permit, whichever date comes first.

Resolute's permit application is administratively complete and EPA has completed its technical review of the application. The well has passed a mechanical integrity test and is cased and cemented to prevent the movement of fluids into an underground source of drinking water. A cement bond log was run in the well to assess the casing/cement/ borehole bond integrity and the log indicates that the cement placement and bonding in the borehole/casing annulus will prevent fluid movement into USDWs penetrated by the well.

The source of injection fluids will be saltwater produced in association with oil and gas production from current and future Paradox Formation oil wells operated by Resolute in the Aneth Unit. The average total dissolved solids (TDS) content of injection fluids is approximately 91,000 ppm based on fluid analyses of water from the Aneth Unit water injection plant. The water will be injected into the Mississippian Leadville Formation at a depth of approximately 7,058 to 7,412 feet. The Leadville Formation waters contain TDS of approximately 44,000 ppm, based on the analysis of formation water produced from the Leadville Formation in the C-113 SWD well.

The Applicant has notified all interested parties within the Area of Review, which includes the local landowners, land-users, Navajo Nation, Bureau of Land Management, Bureau of Indian Affairs, and the State of Utah.

The Applicant has also requested a permit from Navajo Nation EPA (NNEPA, Permit No. NN 18) for drilling, construction, and operation of this same Class II disposal well. Issuance of this NNEPA permit is currently under review by NNEPA and is pending. Furthermore, the Utah Division of Oil Gas and Mining issued an Underground Injection Control Permit for this well effective October 23, 2007.

This Statement of Basis describes the specific permit conditions and the basis for those conditions under authority of the Underground Injection Control (UIC) regulations and the UIC provisions of the Safe Drinking Water Act.

BRIEF SUMMARY OF PART II. SPECIFIC PERMIT CONDITIONS

SECTION A. WELL CONSTRUCTION

1. Casing and Cementing

The vertical wellbore was drilled and completed pursuant to the State of Utah drilling and conversion permits. The well construction is completed and the wellbore schematic diagram can be seen in Appendix C of the permit.

The surface casing is 13-3/8 inches in diameter, set at 82 feet and cemented to the surface with 100 sacks of class G cement. The intermediate casing is 11-3/4 inches in diameter, set at 1,618 feet and cemented to surface with 136 sacks of class G cement. The long string casing is 7-5/8 inches in diameter, set at 7,602 feet and cemented to surface with 3,526 cubic feet of class G cement from 7,602 feet (TD) to the surface. The injection tubing is 4-1/2 inches in diameter, set with an injection packer assembly at 6,965 feet of depth.

The injection zone is overlain by 286 feet of tight limestone and shale in the Molas Shale and Pinkerton Trail formations, and the 719 feet-thick impervious Paradox Salt section above the Molas Shale, and underlain by at least 190 feet of tight limestone and shales in the Ouray and Elbert formations, providing confining layers to the injection zone at 7,008 to 7,412 feet. The USDWs are protected from the inflow of fluids by surface, intermediate, and long string casing and cement placement in the casing/wellbore-casing annulus of all casing strings, from the casing shoe to the surface. The tubing/packer assembly also provides another layer of protection from inflow of injected fluids into the USDWs.

2. Formation Logging and Testing

The static fluid level and/or injection zone pressure must be measured and reported to the EPA on an annual basis. A step-rate injectivity test may be required for the determination of formation fracture pressure if the applicant seeks to exceed the maximum allowable injection pressure during the life of the well. A Dual Laterolog (DL) was run from total depth (TD) to the intermediate casing shoe, and Gamma Ray/Compensated Neutron Log/Compensated Density Logs (GR/CNL/CDL), a Micro Log (ML), Caliper, and Cement Bond Log/Gamma Ray (CBL/GR) logs were run from TD to the intermediate casing shoe or higher. Step-rate and pressure fall-off tests were conducted in the vertical wellbore and again after the first of four lateral boreholes were drilled, for the determination of the Leadville formation injectivity, fracture gradient, hydraulic conductivity, and static fluid pressure of the injection zone.

3. Monitoring Devices

The Applicant is required to install pressure gauges or FIP fittings with cut-off valves to allow an inspector to obtain injection pressure measurements. A flowmeter shall be installed for measuring flow rates and cumulative volumes injected and a sampling tap shall be installed on the injection pump discharge line for the purpose of periodically obtaining representative samples of the injection fluid. Casing and tubing pressures will be monitored at the surface on a weekly basis by means of pressure/vacuum gauges.

SECTION B. CORRECTIVE ACTION

A circular Area of Review (AOR) of 1.25 miles radius, measured from the surface location of the well, has been proposed by the Applicant. The radius is based on an extension of the longest lateral borehole (#3) to a distance of one-half (1/2) mile from the end of that borehole. The applicant reports that there are no well penetrations of the Leadville Formation within the AOR of the subject well. The permit will be issued based on corrective action considerations associated with the proposed AOR; however, the AOR will be subject to review and possible enlargement based on monitoring of static reservoir pressure. The extent of reservoir pressure buildup will be monitored annually during the term of the permit. Corrective actions will be required to minimize pressure buildup over the permit term if it may endanger USDWs.

Based on the proposed AOR, no corrective action in surrounding wells is required of the Applicant because no wells within the AOR penetrate the Leadville injection zone. Therefore, migration of injected fluids in the proposed well into USDWs is highly unlikely without the existence of communicating faults or fractures that extend from the injection zone more than 5,000 feet upward to the base of the lowermost possible USDW (Navajo Aquifer). No such faults or fractures are known to exist within the AOR.

SECTION C. WELL OPERATION

1. Mechanical Integrity

A mechanical integrity test (MIT) of the casing, tubing, and packer will be conducted prior to commencement of injection operations in the well. The purpose of this test is to ensure there are no significant leaks in the tubing, packer, and casing. The standard MIT procedure requires applying a pressure at least equal to the maximum allowable injection pressure in the tubing/casing annulus for thirty (30) minutes with no more than 5% change in pressure. A differential of at least three-hundred (300) psig between the tubing and tubing/casing annulus will be maintained throughout the test. Demonstrations of mechanical integrity of the injection tubing and casing will be required every five (5) years and within thirty (30) days after any workovers or alterations of the wellbore, prior to resuming injection. An alternative to the standard MIT is to apply a pressure of at least 1,000 psig and perform the MIT every three (3) years.

2. Injection Interval

Injection will be permitted for the Leadville Formation in the subsurface interval at approximately 7,008 to 7,412 feet. Any proposed change of injection formation or enlargement of this interval will require a permit modification, subject to public notice, comment and appeal.

3. Injection Pressure Limitation(s)

The wellhead injection pressure shall not exceed the maximum allowable injection pressure, initially calculated by multiplying the actual depth to the top of the injection interval by 1.0 psi/foot, less the hydrostatic pressure of the injection fluid. The maximum injection pressure may be increased only if a valid step-rate test is conducted by the operator and is witnessed and approved by the EPA. Injection pressure shall not exceed the fracture pressure of the injection zone as determined by the EPA from the analysis of step-rate test results.

4. Injection Volume Limitation:

The proposed average injection rate is 7,500 barrels per day and the proposed maximum injection rate is 10,000 barrels per day. The cumulative volume that would be injected into the Leadville interval, assuming the average injection rate of 7,500 barrels per day is applied over the 10-year term of the permit, equals 27.375 million barrels. The storage capacity of the Leadville injection zone within the proposed area of review (AOR) is an estimated 183 million barrels, based on Leadville Formation properties and injection zone thickness determined from wireline log analysis. The proposed AOR is defined by a cylinder with a radius of 6600 feet from the wellbore. The above calculations are based on the following assumptions and formation properties: a homogeneous injection zone, average effective porosity of 10 %, residual water and gas saturation of 50 %, and net thickness of 150 feet.

The potential for migration of formation fluids out of the injection zone and into USDWs will be limited by the fact that none of the wells in the proposed AOR penetrate the injection zone and there are no known faults or fractures that would allow migration of fluids into USDWs within the proposed AOR. Endangerment of USDWs from migration of injected and formation fluids is therefore unlikely. Pressure build-up in the injection zone will be monitored annually during the term of the permit, and corrective actions will be taken if pressure build-up may endanger USDWs.

SECTION D - MONITORING, RECORD KEEPING, AND REPORTING OF RESULTS

The Applicant is required to sample and analyze the water quality of the injected fluids at annual intervals and whenever the source of the injection fluid changes. Water samples shall be analyzed for TDS, major ions, pH, specific conductivity, specific gravity, and viscosity. Measurements of the injection pressure, annulus pressure, injection rate, and cumulative volume must be observed weekly and recorded at least once per month. The Applicant is required to submit an Annual Monitoring Report to the EPA summarizing the monitoring of injection rates, volumes, pressures, and injected fluid, and any major changes in the characteristics or sources of injected fluid. Static fluid levels and/or pressures will be measured and will be reported to the EPA on an annual basis.

SECTION E - PLUGGING AND ABANDONMENT

The EPA has reviewed the plugging and abandonment (P&A) plan submitted by the applicant. The P&A plan is incorporated into the permit as Appendix A. **The current estimated cost of plugging and abandoning the well must be provided and approved prior to issuance of the final permit**, and will be reviewed periodically to ensure that the P&A cost estimate remains current and accurate. The plugging plan and procedure will be reviewed prior to commencement of plugging operations to ensure that the well is abandoned in a manner that protects USDWs.

SECTION F - FINANCIAL RESPONSIBILITY

The Applicant must furnish an acceptable financial instrument prior to issuance of the final permit, sufficient to guarantee current costs of plugging and abandoning the subject well in the event the Applicant fails to properly plug and abandon the well, whenever that may become necessary. The EPA is the specified beneficiary of the aforementioned surety instruments. The EPA will review and may require updating of the financial responsibility mechanism periodically as plugging and abandonment costs increase, or as other circumstances may require.